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List of Acronyms

ACE	Area control error
AGC	Automatic generation control
APC	Active power control
BAAL	Balancing Authority ACE Limit
BA	Balancing authority
CAISO	California Independent System Operator
FERC	Federal Energy Regulatory Commission
FFR	Fast frequency response
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PFR	Primary frequency response
POI	Point of interconnection
PPC	Power plant controller
PV	Photovoltaic
ROCOF	Rate of change of frequency
RPS	Renewable portfolio standard
SCADA	Supervisory Control and Data Acquisition

Executive Summary

The California Independent System Operator (CAISO), First Solar, and the National Renewable Energy Laboratory (NREL) conducted a demonstration project on a large utility-scale photovoltaic (PV) power plant in California to test its ability to provide essential ancillary services to the electric grid. With increasing shares of solar- and wind-generated energy on the electric grid, traditional generation resources equipped with automatic governor control (AGC) and automatic voltage regulation controls—specifically, fossil thermal—are being displaced. The deployment of utility-scale, grid-friendly PV power plants that incorporate advanced capabilities to support grid stability and reliability is essential for the large-scale integration of PV generation into the electric power grid, among other technical requirements.

A typical PV power plant consists of multiple power electronic inverters and can contribute to grid stability and reliability through sophisticated "grid-friendly" controls. In this way, PV power plants can be used to mitigate the impact of variability on the grid, a role typically reserved for conventional generators. In August 2016, testing was completed on First Solar's 300-MW PV power plant, and a large amount of test data was produced and analyzed that demonstrates the ability of PV power plants to use grid-friendly controls to provide essential reliability services. These data showed how the development of advanced power controls can enable PV to become a provider of a wide range of grid services, including spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, and frequency regulation to power quality. Specifically, the tests conducted included various forms of active power control such as AGC and frequency regulation; droop response; and reactive power, voltage, and power factor controls.

This project demonstrated that advanced power electronics and solar generation can be controlled to contribute to system-wide reliability. It was shown that the First Solar plant can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in AGC, primary frequency control, ramp rate control, and voltage regulation. For AGC participation in particular, by comparing the PV plant testing results to the typical performance of individual conventional technologies, we showed that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The plant's ability to provide volt-ampere reactive control during periods of extremely low power generation was demonstrated as well.

The project team developed a pioneering demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation's value from being a simple variable energy resource to a resource that provides a wide range of ancillary services. With this project's approach to a holistic demonstration on an actual, large, utility-scale, operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data.

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1 Introduction

Solar photovoltaic (PV) generation is growing rapidly. At the end of 2015, the United States had 25 GW of installed solar PV capacity, with an additional 1.8 GW of concentrating solar power [1], [2]. As PV continues to grow, questions are arising about the ability of PV to contribute to maintaining grid reliability. In this study, we demonstrated various grid-friendly controls on First Solar's 300-MW PV plant located in the California Independent System Operator's (CAISO's) footprint. Our analysis shows that advanced power electronics and solar generation can be controlled to contribute to system-wide reliability. More specifically, we show that the First Solar plant can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in automatic generation control (AGC), primary frequency control, ramp rate control, and voltage regulation. For AGC participation in particular, by comparing the PV plant testing results to the typical performance of conventional individual technologies, we showed that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The plant's ability to provide volt-ampere reactive (VAR) control during periods of extremely low power generation was demonstrated as well.

The project team—consisting of experts from CAISO, First Solar, and the National Renewable Energy Laboratory (NREL)—developed a demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation's value from being a simple variable energy resource to a resource that provides a wide range of ancillary services. With this project's approach to a holistic demonstration on an actual, large, utility-scale, operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data. If PV-generated power can offer a supportive product that benefits the power system and is economic for PV power plant owners and customers, this functionality should be recognized and encouraged. This project showed, through real-world testing, that PV power plants can contribute to maintaining grid reliability.

Pioneering work done by NREL, First Solar, and AES in 2015 in West Texas and Puerto Rico provided a detailed understanding of the advanced capabilities offered by modern PV power plants [3]. The current CAISO-First Solar-NREL project is aimed at breaking new barriers to the provision of ancillary services by PV generation in terms of both plant capacity (300 MW) and system-level impacts. Taken as a whole, these three studies show that PV power plants can be used to manage a variety of grid challenges on island systems, isolated interconnections, and within market environments in large synchronous systems.

Renewable energy in the United States accounted for 13.44% of domestically produced electricity in 2015 [3]. California is a leading state for integrating renewable resources and for renewable portfolio standards (RPSs), with approximately 29% of its electricity provided from RPS-eligible renewable sources (including small hydropower) [4]. In addition, California is leading the way in climate change policies that are intended to reduce emissions from all sectors, including electricity, by 40% from 1990 levels by 2030 and by 80% from 1990 levels by 2050. If California is to achieve these goals while enhancing grid reliability, all resources, including renewables, must be leveraged to provide essential reliability services.

Rapid penetrations of variable renewable generation into an electric grid are changing the ways power system operators manage their systems. Higher levels of variable generation are creating real-time reliability and operational changes. For example, the California Independent System Operator (CAISO) is trying to adapt to rapid increases in its solar PV generation during sunrise and rapid losses in solar production during sunset.

CAISO currently has more than 9,000 MW of transmission-connected solar resources within its operational footprint. To meet its RPS goal of 33% by 2020, CAISO is expecting an additional 4,000–5,000 MW of solar. Beyond 2020, to meet a 50% RPS goal, CAISO is expecting an additional 15,000 MW of renewable resources, and a significant portion of this is anticipated to be transmission-connected solar PV because of the expected reduction in the price of solar panels (Figure 1). Thus, the capability of solar PV resources to provide essential reliability services is necessary to achieve a low-carbon grid.

Figure 1. CAISO's expected renewable capacity build-out to meet its 50% RPS goal.
Illustration from CAISO

In addition, CAISO has experienced a significant increase in rooftop solar PV installations (Figure 2). Currently, more than 5,000 MW of rooftop solar PV is installed within CAISO's footprint, and it is expected to exceed 9,000 MW by 2020. Rooftop solar PV does not count toward RPS, but it does have an impact on grid operations, especially during sunrise and sunset.

Estimated Behind the Meter Solar PV Build-out through 2021

BTM Solar PV	2015	2016	2017	2018	2019	2020	2021
	3,695	4,903	5,976	7,054	8,146	9,309	10,385
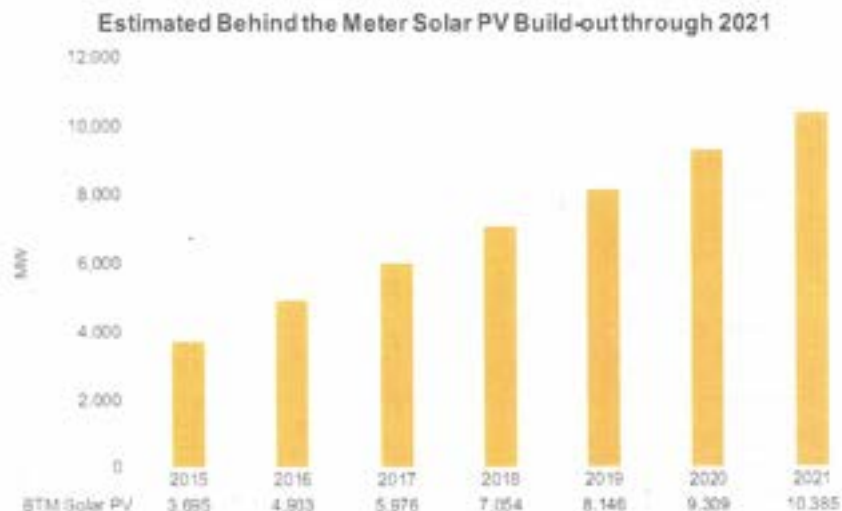
Figure 2. CAISO's expected build-out of rooftop solar PV. *Illustration from CAISO*

High levels of solar generation during midday hours are already contributing to oversupply, especially on light load days when renewable production is high. Therefore, it is during these conditions that opportunity is created if renewable resources could provide essential reliability services that have traditionally been provided by conventional resources. Sharp changes in the real-time ramping needs are also happening during afternoon-to-evening hours. This is especially evident during the spring and fall months, when loads are relatively light and hourly penetrations of renewable generation are high. In its "duck chart" (Figure 3), CAISO shows these integration changes and opportunities for a typical spring day as a significant drop in its midday net load is met by an increased share of PV in the system. These changes and opportunities to leverage the capability of these new resources are growing at a faster rate than previously expected; and during certain days in the spring of 2016, CAISO's minimum net load was already less than the predicted 2020 level.

Typical Spring Day
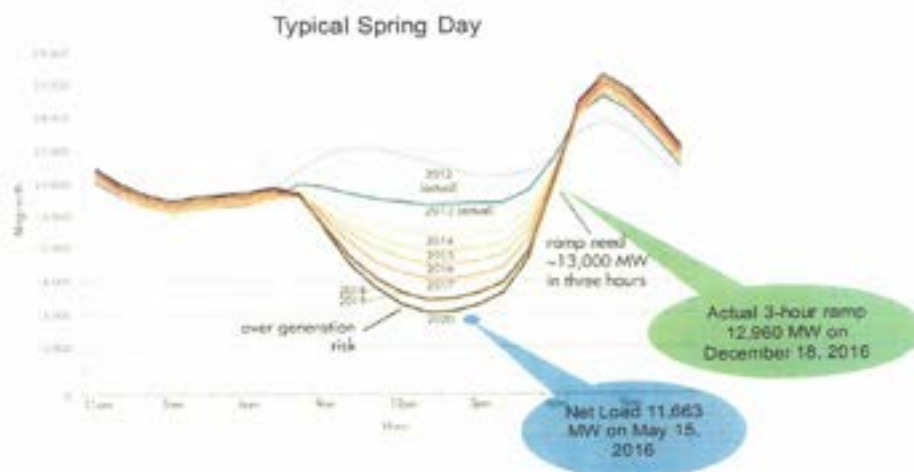
Figure 3. CAISO duck chart. *Illustration from CAISO*

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Because of low net loads, the risk of oversupply increases, so significant curtailment of renewables took place during certain days in the spring of 2016. An example of this type of curtailment period is shown in Figure 4. During certain daytime hours on April 24, 2016, more than 2 GW of renewable generation were curtailed to maintain reliable operation of the system. With increased curtailment, more opportunity is created if the industry can tap into the controllability of renewable resources and thus reduce reliance on conventional resources to provide such services.

Advanced inverter functions and how projects are designed and operated can help address grid stability problems during such periods. A typical modern utility-scale PV power plant is a complex system of large PV arrays and multiple power electronic inverters, and it can contribute to mitigating the impacts on grid stability and reliability through sophisticated automatic "grid-friendly" controls. Many of the PV control capabilities that were demonstrated in this project have already generally been proven to be technically feasible, and a few areas throughout the world have already started to request or require PV power plants to provide some of them; however, in the United States, utility-scale PV plants are rarely recognized as having these capabilities, and typically they are not used by utilities or system operators to provide electric grid services.
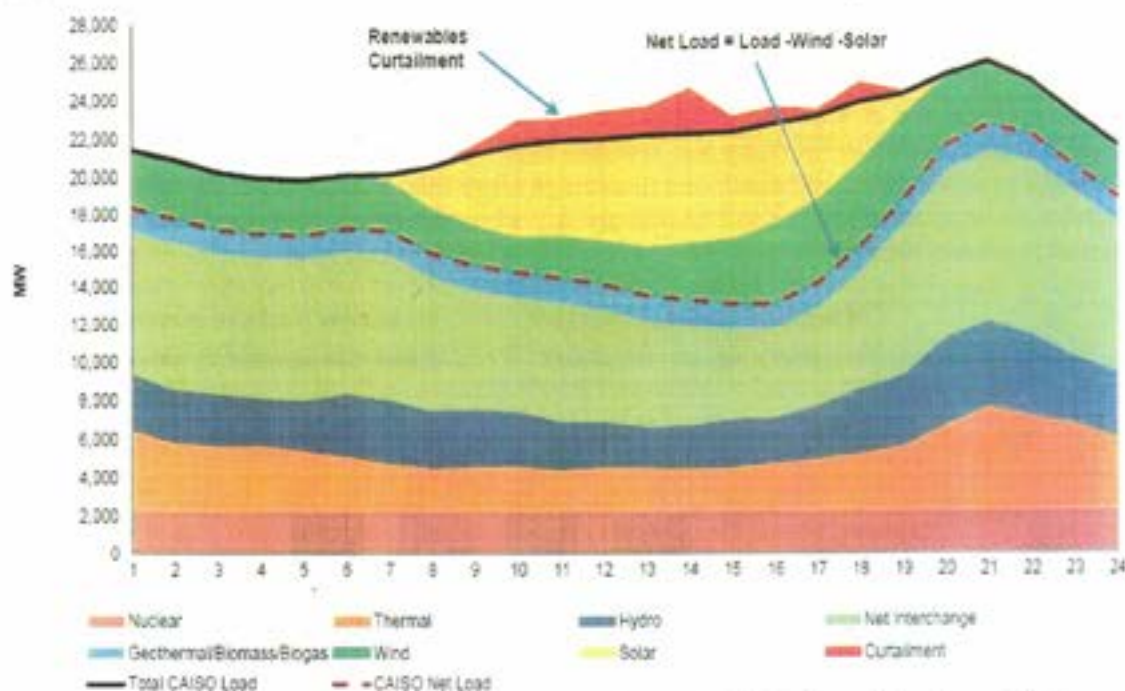
Figure 4. CAISO's generation breakdown for April 24, 2016. *Illustration from CAISO*

CAISO is continually adapting its operational practices and market mechanisms to make the integration of shares of fast-growing variable renewable generation both reliable and economic. This new reality leads to growing needs by CAISO and other independent system operators to:

- Better coordinate between day-ahead and real-time markets
- Increase flexibility in the form of fast ramping capacity

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- Better utilize ancillary service capabilities by variable renewable generation

- Deepen regional coordination

- Implement new market mechanisms incentivizing the participation of renewables in ancillary service markets

- Develop new market products to take advantage of faster and higher-precision ancillary service providers

- Add energy storage capacity

- Align time-of-use rates with system demand.

Currently, regulation-up and regulation-down are two of the four ancillary service products that CAISO procures through co-optimization with energy in the day-ahead and real-time markets. The other two products are spinning and nonspinning reserves. Most ancillary service capacity is procured in the day-ahead market. CAISO procures incremental ancillary services in the real-time market processes to replace unavailable ancillary services or to meet additional ancillary service requirements. A detailed description of the ancillary service market design, which was first implemented in 2009, is provided in CAISO's 2016 market report [5], [6].

From February 20, 2016, through June 9, 2016, CAISO increased the requirements to a minimum of 600 MW for regulation-up and regulation-down in both the day-ahead and real-time markets. Average prices for these two ancillary services increased immediately following the change in requirements in February and reverted to lower levels again in June 2016 (Figure 5). Regulation procurement costs continued to average more than $400,000 per day when the requirements were high and fell to $80,000 per day when the requirements were lowered, beginning on June 10, 2016.
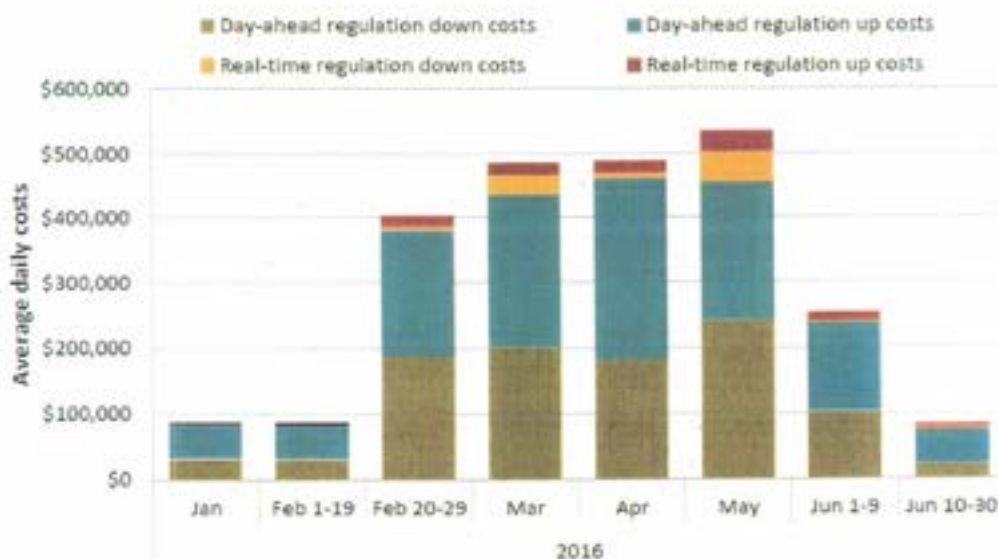
Figure 5. CAISO's average daily regulation procurement costs from January–June 2016.
Illustration from CAISO

In 2012, CAISO implemented standards for importing regulation service [7]. These standards implemented CAISO's tariff provisions relating to the imports of regulation services, either bid or self-provided, by scheduling coordinators with system resources located outside CAISO's balancing authority area. In addition to imported regulation services, regulation provided by PV power plants within CAISO's footprint can become an additional stability tool at CAISO's disposal.

As power system continues to evolve, the Federal Energy Regulatory Commission (FERC) noted that there is a growing need for a refined understanding of the services necessary to maintain a reliable and efficient system. In orders 755 and 784, FERC required improving the mechanisms by which frequency regulation service is procured and enabling compensation by fast-response resources such as energy storage. CAISO is working on a new market design in which aggregated distributed resources (rooftop PV, behind-the-meter batteries, electric vehicles, fast demand response) can bid in its market. In addition, FERC recently issued a notice of proposed rulemaking to enable aggregation of distributed storage and distributed generation [8].

The Electric Reliability Council of Texas and the New York Independent System Operator are also working on similar ancillary service markets for utility-scale and distributed generation [9].

In 2012, the North American Electric Reliability Corporation's (NERC) Integration of Variable Generation Task Force made several recommendations for requirements for variable generators (including solar) to provide their share of grid support, including active power control (APC) capabilities [7, 10]. These recommendations address grid requirements such as voltage control and regulation, voltage and frequency fault ride-through, reactive and real power control, and frequency response criteria in the context of the technical characteristics and physical capabilities of variable generation equipment.

- APC capabilities include:
  - Ramp-rate-limiting controls
  - Active power response to bulk power system contingencies
    - Inertial response
    - Primary frequency response (PFR)
    - Secondary frequency response, or participation in AGC
    - Ability to follow security-constrained economic dispatch (SCED) set points that are sent every 5 minutes through its real-time economic dispatch market software.
- Performance during and after disturbances
  - Fault ride-through
  - Short-circuit current contribution.
- Voltage, reactive, and power factor control and regulation (both dynamic and steady state).

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In 2015, the NERC task force on Essential Reliability Services published a report exploring important directional measures to help the energy sector understand and prepare for the increased deployment of variable renewable generation [11], [12]. According to this report, to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability—essential components of a reliable bulk power system.

The California state legislature passed Senate Bill 350 in the fall of 2015, which requires all utilities in the state to produce 50% of their electricity sales from renewable sources with the objective of reducing carbon emissions. To reach that 50% RPS goal, California operators will need to find additional ways to balance generation and load to manage the variability of increased renewable generation and maintain grid reliability. In this context, the curtailment of renewables can be viewed as a resource, not only a problem. Because wind and solar generation can be ramped up and down, curtailment can become a helpful resource to relieve oversupply and provide frequency regulation and ramping services. In combination with the 1.3-GW California energy storage mandate, ancillary services provided by renewables can enhance system flexibility and reliability and reduce needs in spinning reserves by conventional power plants. Thus, unleashing these capabilities from renewable resources helps achieve the broader objective of a resilient, reliable, low-carbon grid.

Currently, only a few grid operators in the United States are using curtailed renewables as a resource. For example, the Public Service Company of Colorado (PSCO) has means to control its wind generation to provide both up and down regulation reserves (the PSCO has had periods of 60% wind power generation in its system). The PSCO is able to use wind reserves as an ancillary service for frequency regulation by integrating the wind power plants in their footprint to provide AGC. Similar services can be provided by curtailed PV power plants in California; however, regulatory, market, and operational issues need to be resolved for this to become possible [13], [14].

Prior to testing, the team developed a plan that was coordinated with technical experts from First Solar. The test plan is shown in the appendix of this report). The following sections describe the tests and results conducted by the team:

1. CAISO-NREL-First Solar custom-developed test scenarios (conducted on August 24, 2016)

    A. Regulation-up and regulation-down, or AGC tests during sunrise, middle of the day, and sunset

    B. Frequency response tests with 3% and 5% droop settings for overfrequency and underfrequency conditions

    C. Curtailment and APC tests to verify plant performance to decrease or increase its output while maintaining specific ramp rates

    D. Voltage and reactive power control tests

    E. Voltage control at near zero active power levels (nighttime control).

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2. More standardized First Solar's power plant controller (PPC) system commissioning tests (conducted on August 23, 2016)

    A. Automatic manual control of inverters (individual, blocks of inverters, whole plant)

    B. Active power curtailment control, generation failure and restoration control, frequency control validation

    C. Automatic voltage regulation at high and low power generation

    D. Power factor control

    E. Voltage limit control

    F. VAR control.

2 PV Power Plant Description

First Solar constructed a 300-MW AC PV power plant in CAISO's footprint. An aerial photo of the plant using First Solar's advanced thin-film cadmium-telluride PV modules is shown in Figure 6. The plant is tied to 230-kV transmission lines via two 170-MVA transformers (34.5/230 kV). The 34.5-KV side of each transformer is connected to the plant's MV collector system with four blocks each rated 40 MVA. Individual PV inverter units, each rated 4 MVA, operate at 480 VAC and are connected to a 34.5-kV collector system via pad-mounted transformers. Switched capacitor banks are connected to both 34.5-kV buses to meet the power factor requirements of FERC's Large Generator Interconnection Agreement (LGIA) power factor requirements. Two phasor measurement units (PMUs) were set to collect data at the 230-kV sides of both plant transformers.

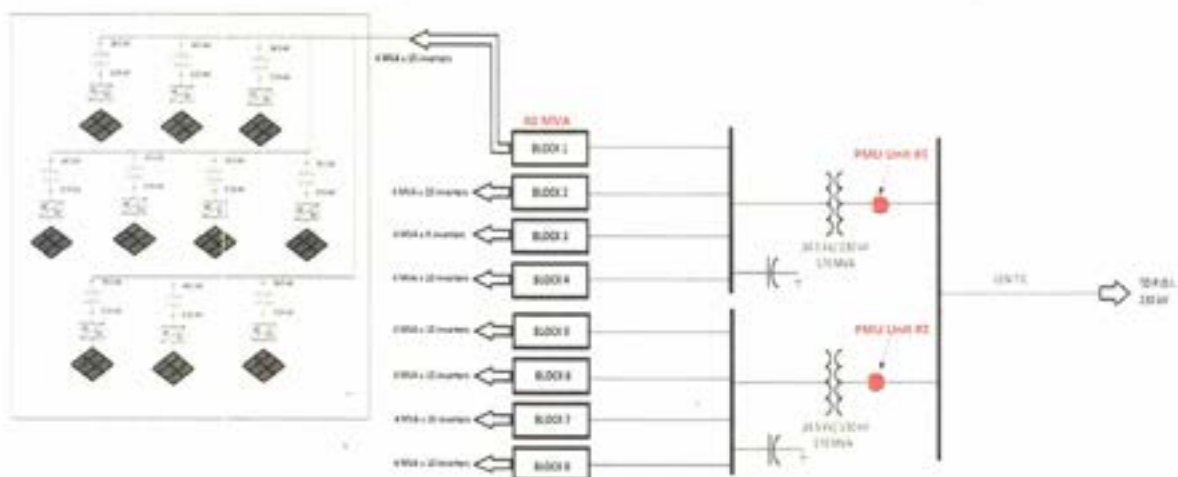Figure 6. Aerial photo of First Solar's 300-MW PV power plant. *Photo from First Solar*

Figure 7. Electrical diagram of First Solar's 300-MW PV plant. *Illustration from First Solar*

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A key component of this tested grid-friendly solar PV power plant is a PPC developed by First Solar. It is designed to regulate real and reactive power output from the PV power plant so that it behaves as a single large generator. Although the plant comprises individual inverters, with each inverter performing its own energy production based on local solar array conditions, the plant controller's function is to coordinate the power output to provide typical large power plant features, such as APC and voltage regulation through reactive power regulation [16].

First Solar's PPC is capable of providing the following plant-level control functions:

- Dynamic voltage and/or power factor regulation and closed-loop VAR control of the solar power plant at the point of interconnection (POI)

- Real power output curtailment of the solar power plant when required so that it does not exceed an operator-specified limit

- Ramp-rate controls to ensure that the plant output does not ramp up or down faster than a specified ramp-rate limit, to the extent possible

- Frequency control (governor-type response) to lower plant output in case of an overfrequency situation or increase plant output (if possible) in case of an underfrequency situation

- Start-up and shutdown control.

The PPC implements plant-level logic and closed-loop control schemes with real-time commands to the inverters to achieve fast and reliable regulation. It relies on the ability of the inverters to provide a rapid response to commands from the PPC. Typically, there is one controller per plant controlling the output at a single high-voltage bus (referred to as the POI). The commands to the PPC can be provided through the Supervisory Control and Data Acquisition (SCADA) human-machine interface or even through other interface equipment, such as a substation remote terminal unit.

Figure 8 illustrates a general block diagram overview of First Solar's control system and its interfaces to other devices in the plant. The PPC monitors system-level measurements and determines the desired operating conditions of various plant devices to meet the specified targets. It manages capacitor banks and/or reactor banks, if present. It has the critical responsibility of managing all the inverters in the plant, continuously monitoring the conditions of the inverters and commanding them to ensure that they are producing the real and reactive power necessary to meet the desired voltage schedule at the POI [16].

A conceptual diagram of the plant's control system architecture is shown in Figure 9. The plant operator can set an active power curtailment command to the controller. In this case, the controller calculates and distributes active power curtailment to individual inverters. In general, some types of inverters can be throttled back only to a certain specified level of active power and not any lower without causing the DC voltage to rise beyond its operating range. Therefore, the PPC dynamically stops and starts inverters as needed to manage the specified active power output limit. It also uses the active power management function to ensure that the plant output does not exceed the desired ramp rates, to the extent possible. It cannot, however, always accommodate rapid reductions in irradiance caused by cloud cover.
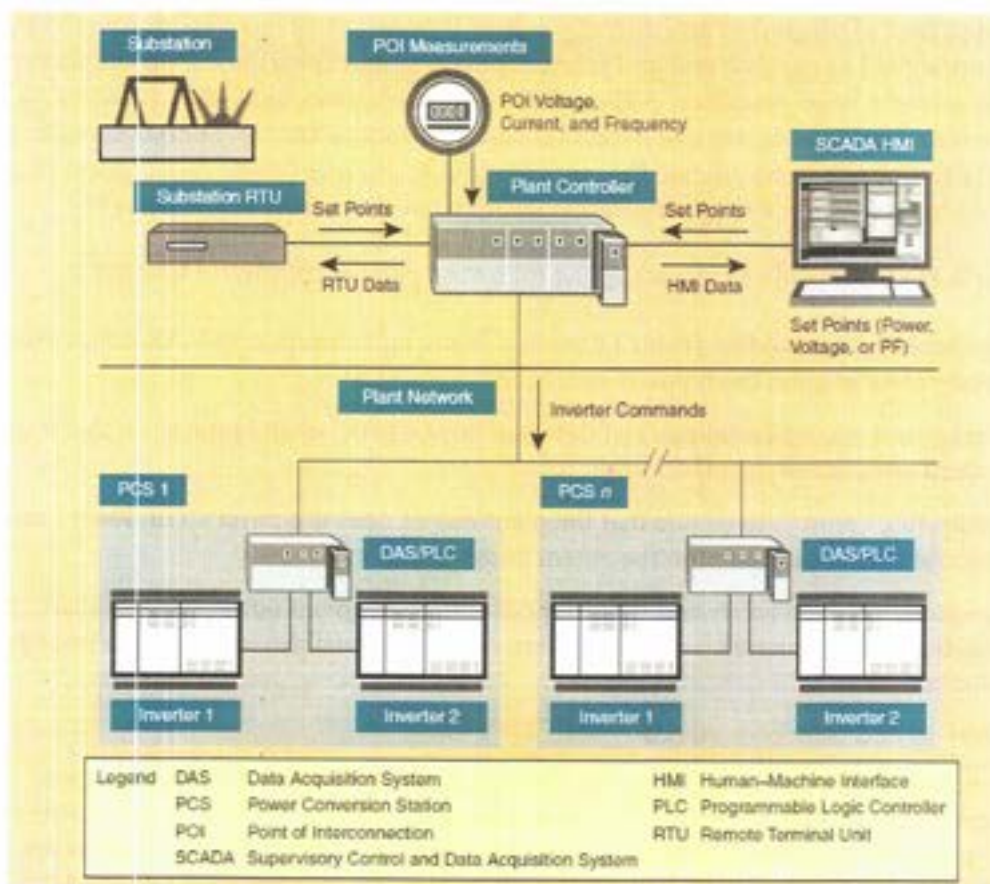
Figure 8. General diagram of First Solar's PV power plant controls and interfaces.
Illustration from First Solar
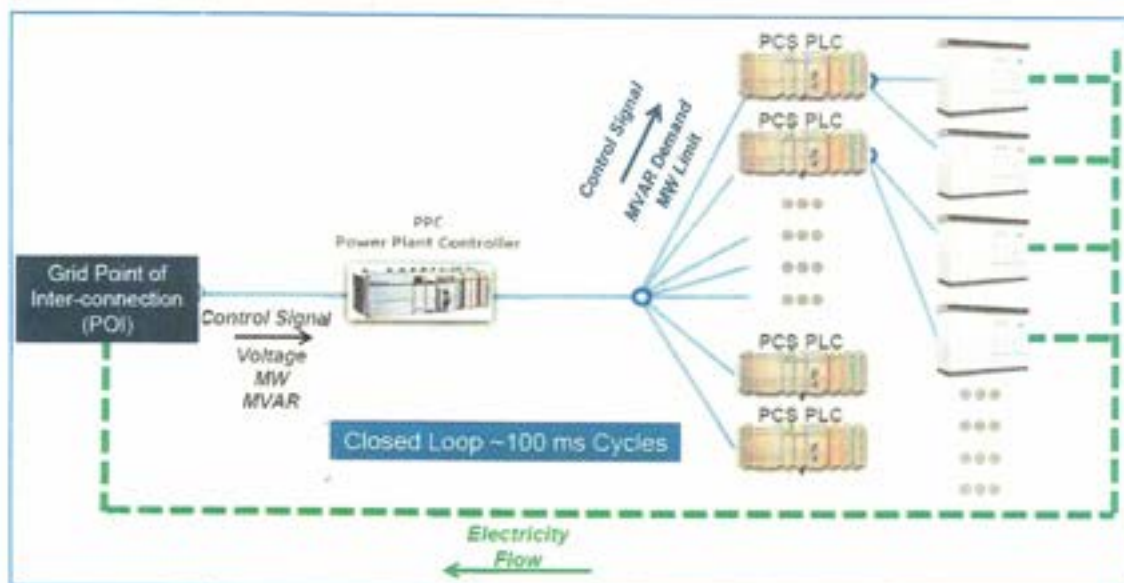
Figure 9. Diagram of First Solar's PV power plant control system architecture.
Illustration from First Solar

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The testing of the 300-MW plant within CAISO's footprint was conducted remotely by the First Solar team from their operations center located in First Solar's corporate offices, in Tempe, Arizona (Figure 10). As a NERC-registered generator operator, the First Solar staff was capable of remotely supervising the ongoing testing activities at the 300-MW PV plant in California, tracking the plant's performance and making changes to test set point and plant control parameters from the center in Arizona.

Figure 10. First Solar's operations center in Tempe, Arizona. *Photo from First Solar*

3 AGC Participation Tests for First Solar's 300-MW PV Power Plant

3.1 Description and Rationale for AGC Tests

The purpose of the AGC tests is to enable the power plant to follow the active power set points sent by CAISO's AGC system. The set point signal is received by the remote terminal unit in the plant substation and then scaled and routed to the PPC in the same time frame. When in AGC mode, the PPC initially set the plant to operate at a power level that was 30 MW lower than the estimated available peak power to have headroom for following the up-regulation AGC signal (see hypothetical example in Figure 11). The lower boundary of AGC operation can be set at any level below available peak power, including full curtailment if necessary.
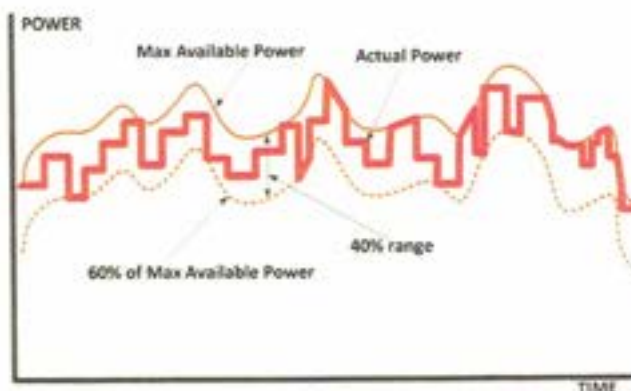
Figure 11. Concept of AGC following by a PV power plant (e.g., with 40% headroom).
Illustration from NREL

CAISO's AGC is normally set to send a direct MW set point signal to all participating units every 4 seconds. All ramp-rate settings in the PV power plant's PPC were set at very high level of 600 MW/min (10 MW/sec) during the AGC tests. AGC control logic for a balancing authority with interconnections (such as CAISO) is based on determining the:

- Area's total desired generation
- Base points for each AGC participating unit
- Regulation obligation for each AGC participating unit.

Area control error (ACE) is an important factor used in AGC control. For a balancing authority area, ACE is determined as:

$$ACE = -\Delta P_{tie} - 10B(f_a - f_s) + I_{ME} + I_T \tag{1}$$

where ΔP_{tie} is the net tie-line interchange error, B is the frequency bias (MW/0.1Hz); f_a and f_s are the actual measured and scheduled frequencies (typically 60 Hz, but they can also be 59.8 Hz or 60.2 Hz during time error corrections), respectively; and I_{ME} and I_T are the meter error correction and time error correction factors, respectively (MW). The ACE value is then used by the AGC control logic to determine the total desired generation that will drive it to zero. The desired generation for each participating generating unit is split into two components: the base

point and regulation. The base point for each generating unit is set at its economic dispatch point, and the system's total regulation is calculated as the difference between the total desired generation and the sum of the base points for all AGC participating units. The total regulation for the whole system is allocated among all participating regulating units. The 300-MW plant under test is considered as one plant-level generating unit, and individual inverter outputs are not considered by CAISO's operations. Various unit-specific parameters are used in its regulation allocation, such as ramp rates and operating limits. Figure 12 shows a general diagram of CAISO's AGC distributing set point signals to individual generating units. The raw ACE signal is filtered first, and it is then processed by a proportional-integral (PI) filter that has proportional and integral control gains. The filtered ACE is then passed to the AGC calculation and distribution module that generates the ramp-limited AGC set points for the individual participating units based on their participation factor, dispatch status, available headroom, unit physical characteristics, etc., as shown in Figure 12.
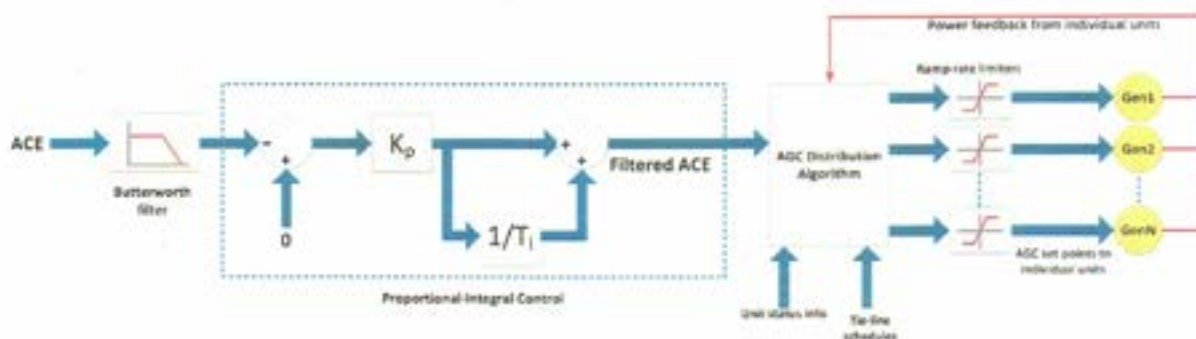
Figure 12. Simplified diagram of CAISO's AGC system. *Illustration from NREL*

AGC operates in conjunction with supervisory control and data acquisition (SCADA) systems [17]. SCADA gathers information on system frequency, generator outputs, and actual interchange between the system and adjacent systems. Using system frequency and net actual interchange, plus knowledge of net scheduled interchange, an AGC system determines the system's energy balancing needs with its interconnection in near real time. CAISO's SCADA system polls sequentially for electric system data with a periodicity of 4 seconds. The degree of success of AGC in complying with balancing and frequency control is manifested in a balancing authority's control performance compliance statistics and metrics as defined by NERC's control performance standards (CPS). In particular, CPS1 is a measure of a balancing authority's long-term frequency performance with the control objective to bound excursions of an average 1-minute frequency error during 12 months in the interconnection. CPS1 allows for evaluating how well a balancing authority's ACE performs in conjunction with the frequency error of the whole interconnection. CPS2 is a measure of the balancing authority's ACE during all 10-minute periods in a month with the control objective to limit ACE variations and bound unscheduled power flows among balancing authority areas.

NREC's Standards Committee approved the replacement of CPS2 with the Balancing Authority ACE Limit (BAAL) in June 2005. BAAL is unique for each balancing authority and provides dynamic limits for its ACE value limits as a function of its interconnection frequency. The objective of BAAL is to maintain the interconnection frequency within predefined limits. A field trial of BAAL began in the Eastern Interconnection in July 2005 and in the Western

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Interconnection in March 2010. Enforcement of BAAL began on July 1, 2016 [18]. Both CPS1 and BAAL scores are important metrics for understanding the impacts of variable renewable generation on system frequency performance. NERC's reliability standards require that a balancing authority balances its resources and demand in real time so that the clock-minute average of its ACE does not exceed its BAAL for more than 30 consecutive clock-minutes.

PV generation participation in CAISO's AGC is expected to maintain CPS above the minimum NERC requirements and BAAL within predefined operating limits and avoid degradation in reliability. AGC participation by faster and higher-precision responsive generation is potentially more valuable because these types of generation allow for applying controls at the exact moment in time and exact amount needed by the system. Faster AGC control is desirable because it facilitates more reliable compliance with NERC's operating standards at relatively less regulation capacity procurements [19]. Currently, CAISO practices and markets do not differentiate between faster and slower providers, with the exception of some minimum ramping capabilities. The data produced by AGC testing of the 300-MW PV plant in California are intended to provide real field-measured results to confirm the above-described benefits and facilitate the transition to improved ancillary service markets that value and incentivize superb performance by inverter-coupled renewable generation.

3.2 AGC Test Results

The AGC tests were conducted on August 24, 2016, at three different solar resource intensity time frames: (1) sunrise, (2) middle of the day (noon–2 p.m.), and (3) sunset (for 20 minutes at each condition). Historic 4-second AGC signals that CAISO previously sent to another regulation-certified resource of similar capacity were provided to the plant controller.

The 300-MW PV plant under test was not connected to CAISO's AGC system because the plant's owner did not request this control option at the time of construction; instead, historical CAISO ACE data were provided to the PPC for AGC performance testing. Each test was conducted using actual 4-second AGC signals that CAISO had previously sent to a regulation-certified resource of similar size. The historical AGC signal provided by CAISO had a regulation range of 30 MW, or 10% of rated plant power (Figure 13). This signal is represented as ΔP_{AGC} in the equation below:

$$P_{command} = (P_{available} - 30MW) + \Delta P_{AGC} \tag{2}$$

where $P_{available}$ is the maximum available instantaneous power that the plant can produce for a given solar irradiation conditions, and $P_{command}$ is the actual commanded MW set point sent to the PPC.
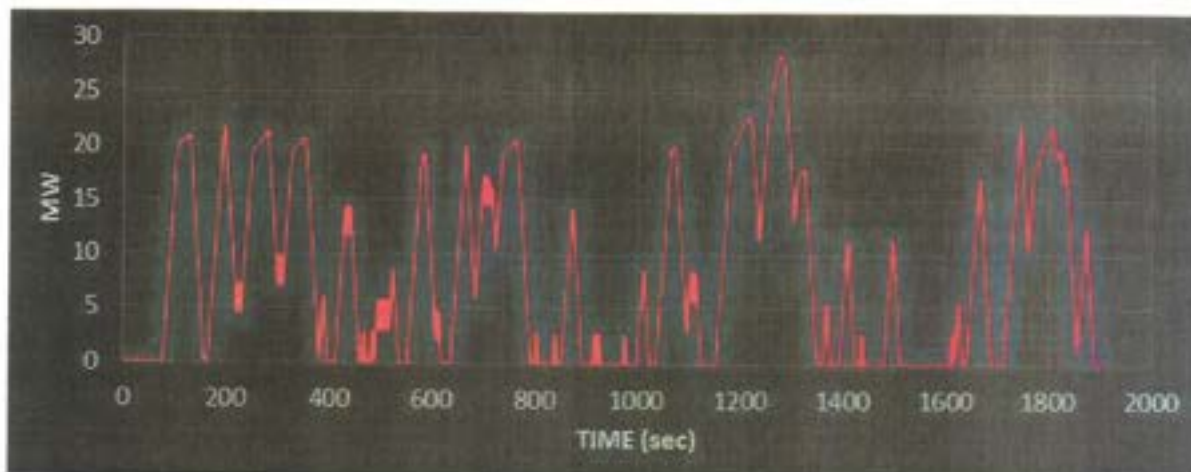
Figure 13. Historic CAISO AGC signal used in testing. *Illustration from NREL*

In this way, the plant's response to the AGC-like set point signal can be tested within a 30-MW range. CAISO's regulation system has a significant total ramping capability for shorter periods of time. Longer ramps may cause regulation problems after faster units exhaust their regulation range. CAISO's real-time economic dispatch software would try to return units that are not awarded service to their preferred point of operation (POP), so sufficient up-regulation and down-regulation capabilities can be maintained. Because the plant under test was not participating in CAISO's real AGC scheme, the adopted method of AGC mimicking provides a sufficient approximation of real conditions because both the up-regulation and down-regulation characteristics of the plant can be tested.

For this PV plant to be able to maintain the desired regulation range (30 MW in this case), the plant PPC must be able to estimate the available aggregate peak power that all the plant's inverters can produce at any point in time. The available power is normally estimated by an algorithm that considers solar irradiation, PV module I-V characteristics and temperatures, inverter efficiencies, etc. The plant under test did not have this estimation function because the plant owner did not request it during construction; instead, the project team implemented a less sophisticated approach to evaluate the available maximum power. For this purpose, a single 4-MVA inverter was taken from the APC scheme by the First Solar team, and it was set to operate at the power level determined by its maximum power point tracking (MPPT) algorithm. The measured AC power of this inverter was used as an indicator of available power for the other 79 inverters (80 inverters total). The available maximum power was then calculated as:

$$P_{available} = 79 \times P_i^{MPPT} \tag{3}$$

where P_i^{MPPT} is the measured AC power of the single inverter that was designated to operate at its MPPT point. Therefore, Eq. 2 can be rewritten as:

$$P_{command} = (79 \times P_i^{MPPT} - 30MW) + \Delta P_{AGC} \tag{4}$$

So the aggregate power command sent to the PPC for the remaining 79 inverters was calculated using Eq. 4. This method has inherent uncertainties because it assumes uniform solar irradiation conditions across the whole 300-MW plant. Fortunately, cloud conditions were favorable for this

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method to be acceptable because there was a clear sky above the plant during most of the day on August 24. Of course, under moving cloud conditions the accuracy of this method would drop significantly due to the large geographical footprint of the 300-MW PV plant. The importance of accurate peak power estimation for any type of up-regulation was also emphasized in Ref. 11, and it is a crucial factor for AGC performance accuracy by PV plants.

The measured 1-second time series for the August 24, 2016, AGC tests are shown in Figures 14–18. In particular, Figure 14 shows the results of the morning AGC test. The test started when the plant was commanded to curtail its production to a lower level (orange trace), which was 30 MW below its available peak power (green trace), according to Eq. 4. The AGC signal was then fed to the PPC (red trace), so the plant output (yellow trace) was changing accordingly, demonstrating good AGC performance by following the set point during this period of smooth power production. A similar test was conducted during the peak production hour, as shown in Figure 15. A magnified view of the same test is shown in Figure 16 allowing a closer look to the plant AGC performance. The plant's response to each new AGC set point is almost immediate; however, there were periods when the plant was not able to reach the set point with this high level of precision. This mismatch can be explained by the internal active ramp rate limit in individual inverters. The absolute control error for the same test is small, as shown in Figure 16, and it is confined within the range of ±5 MW (or ±1.67% of the plant's rated power capacity).
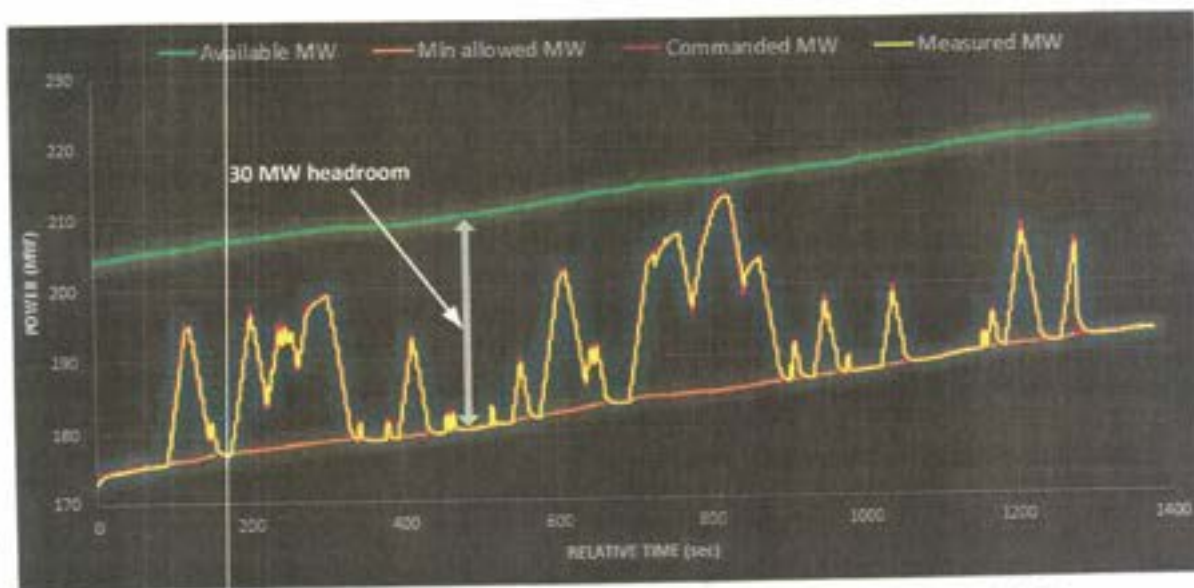

Figure 14. Morning AGC test (9:47 a.m.–10:10 a.m.). *Illustration from NREL*
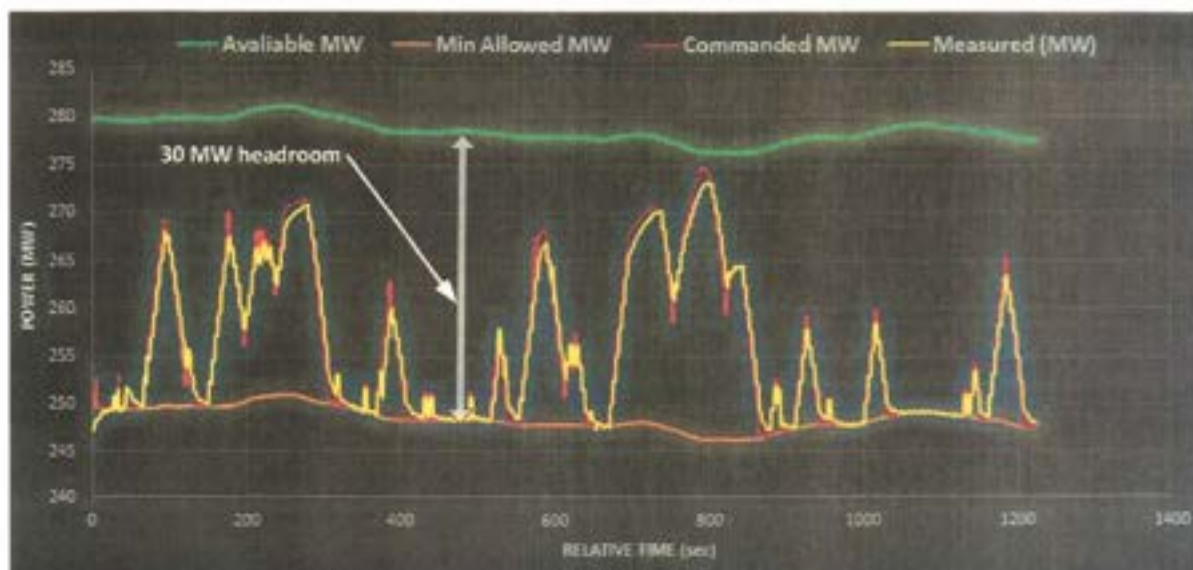
Figure 15. Midday AGC test (12:40 p.m.–1 p.m.). *Illustration from NREL*
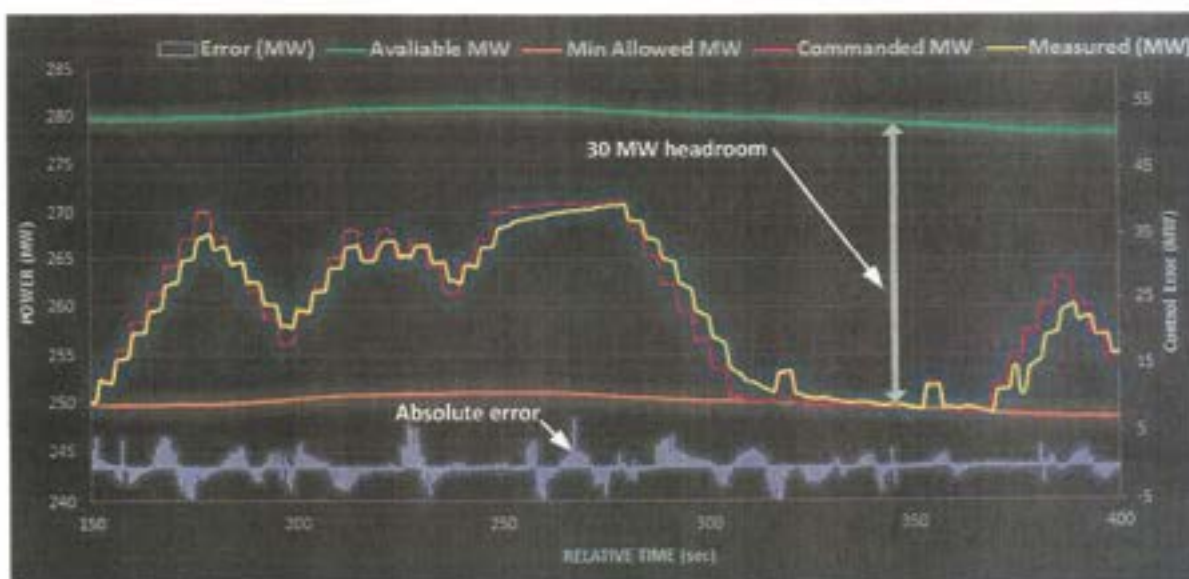
Figure 16. Midday AGC test (12:40 p.m.–1 p.m.) magnification. *Illustration from NREL*

Results of the AGC test conducted during the afternoon are shown in Figure 17. The plant demonstrated similar AGC performance as in the previous cases; however, a cloud front was moving over the plant on the afternoon of August 24, which introduced variability in the plant's output. During these periods, the available peak power from the plant was reduced significantly, causing the AGC set point to decrease as well, according to Eq. 4; however, even during these periods, the plant demonstrated good AGC performance by closely following the commanded set point, as shown in Figure 18 for one such event.

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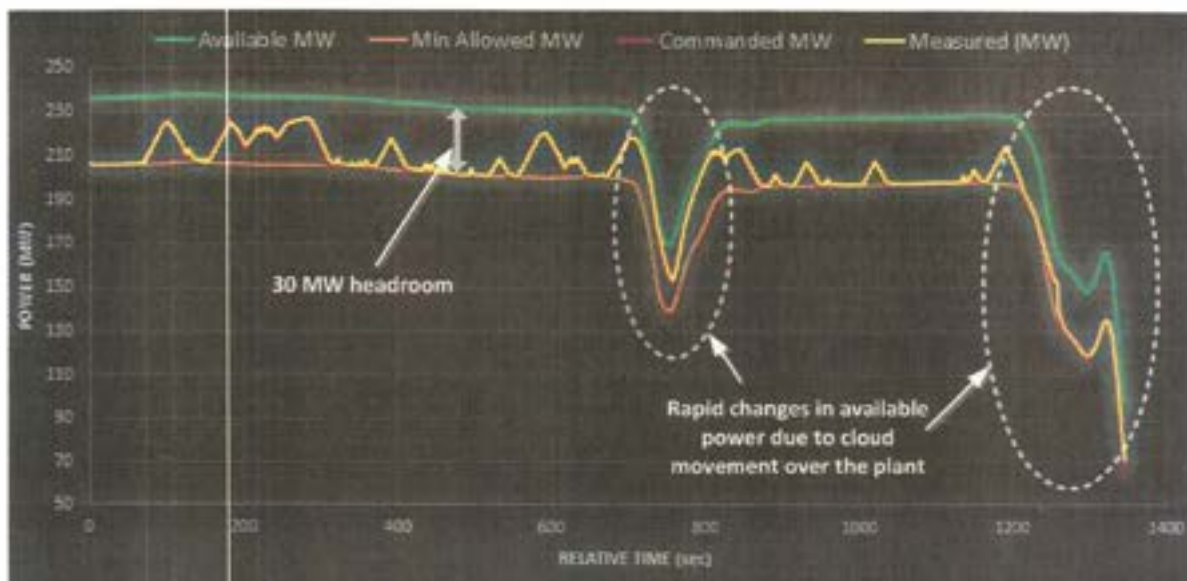
Figure 17. Afternoon AGC test (2:54 p.m.–3:16 p.m.). *Illustration from NREL*
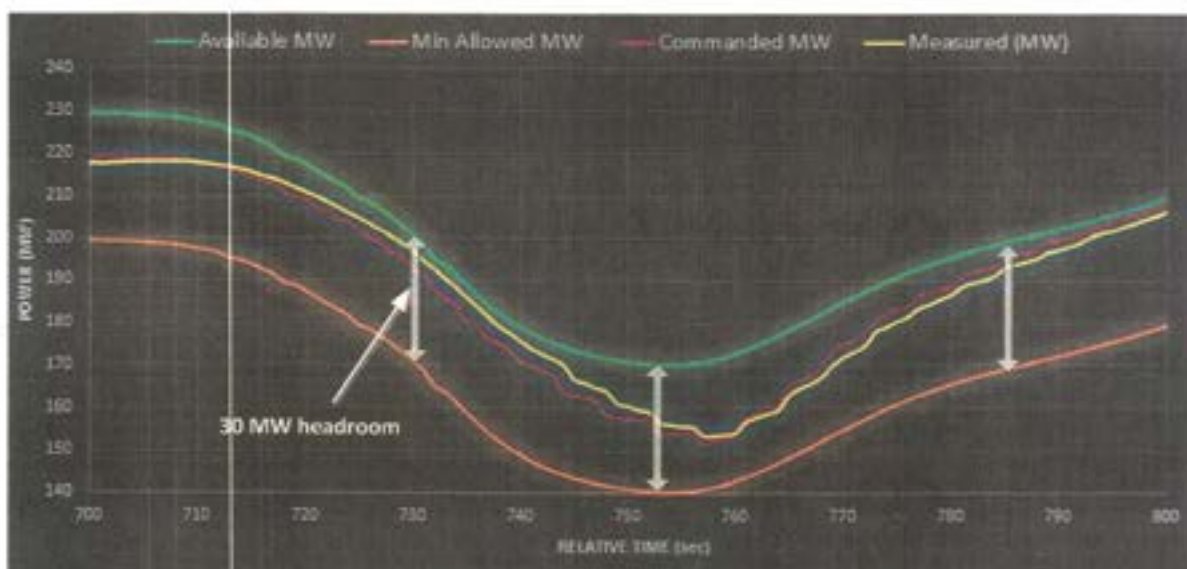
Figure 18. Afternoon AGC test (2:54 p.m.–3:16 p.m.) magnification. *Illustration from NREL*

The performance results for all three AGC tests are consolidated in an X-Y plot (Figure 19) that shows the linear correlation between the commanded and measured plant power for the morning, midday, and afternoon testing periods (red, blue, and green dots, respectively). The slope and offset of the linear regression for each test indicate low scatter and good linearity. In addition, the R-squared values of the correlation coefficients for each time period also show a high degree of correlation between the set point and measured plant power.

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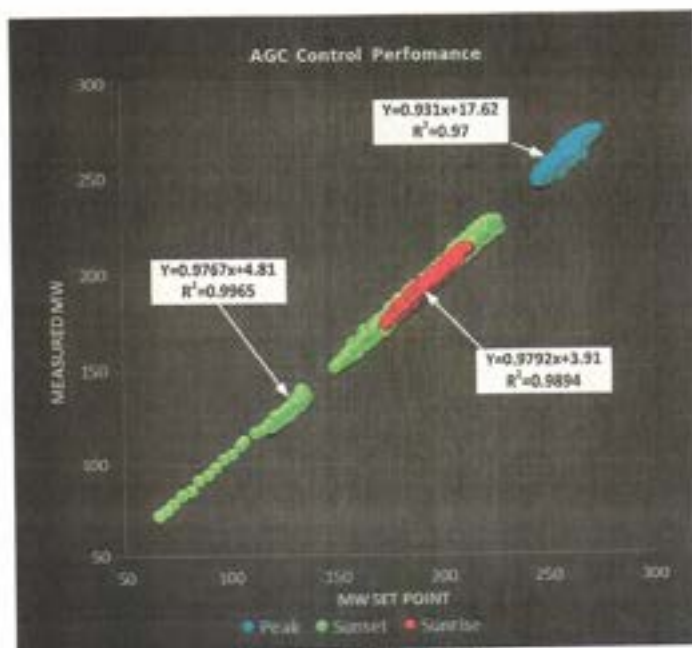
Figure 19. AGC performance for three time periods. *Illustration from NREL*

The relative AGC control error as a percentage of installed plant capacity for all three AGC tests is shown in Figure 20 for a 20-minute time interval for comparison. Table 1 lists the mean, min/max, and standard deviation values of the AGC control error. The mean value of the AGC control error during the whole period of testing for all three data sets is very low (-0.013% of the plant's rated capacity), with standard deviation of error equal to 0.439%.

Figure 20. AGC control error for all three tests. *Illustration from NREL*

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Table 1. AGC Control Error Statistics

	Sunrise	Peak	Sunset	Total for the Period of Testing
Mean error (% of rated power)	0.02	0.0	-0.06	-0.01
Min error (% of rated power)	-1.16	-1.85	-2.1	-2.1
Max error (% of rated power)	1.25	2.35	2.12	2.35
Standard deviation (% of rated power)	0.31	0.47	0.51	0.44

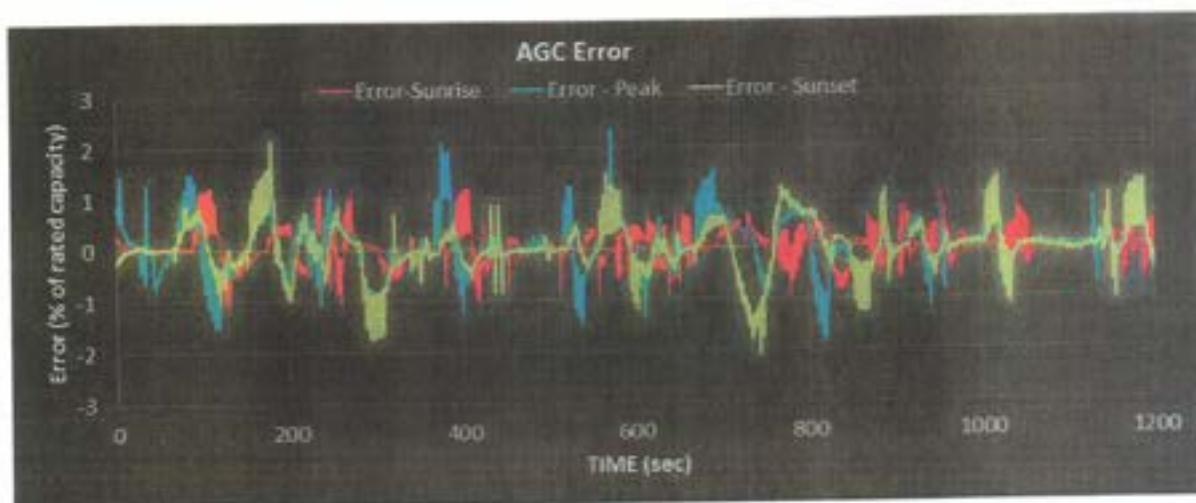The frequency distribution of the AGC control errors for all three periods of observation are shown in Figure 21 in logarithmic scale as a visual representation of the difference between the number of error magnitude occurrences for each test. These distribution shapes are not exactly symmetric, but they are still concentrated around the center with visible tails. Only a few AGC control errors with large magnitudes occurred during the periods of observation. Of course, longer testing (many days or weeks) under different cloud conditions will be required to collect sufficient statistics on AGC control accuracy. Yet even such a short testing opportunity allows some preliminary conclusions on the accuracy of AGC control by a large utility-scale power plant. These results also suggest that relatively small and short-term energy storage can help reduce the AGC error to essentially 0% by taking care of small control inaccuracies due to cloud impact and uncertainties of peak power calculation methods.
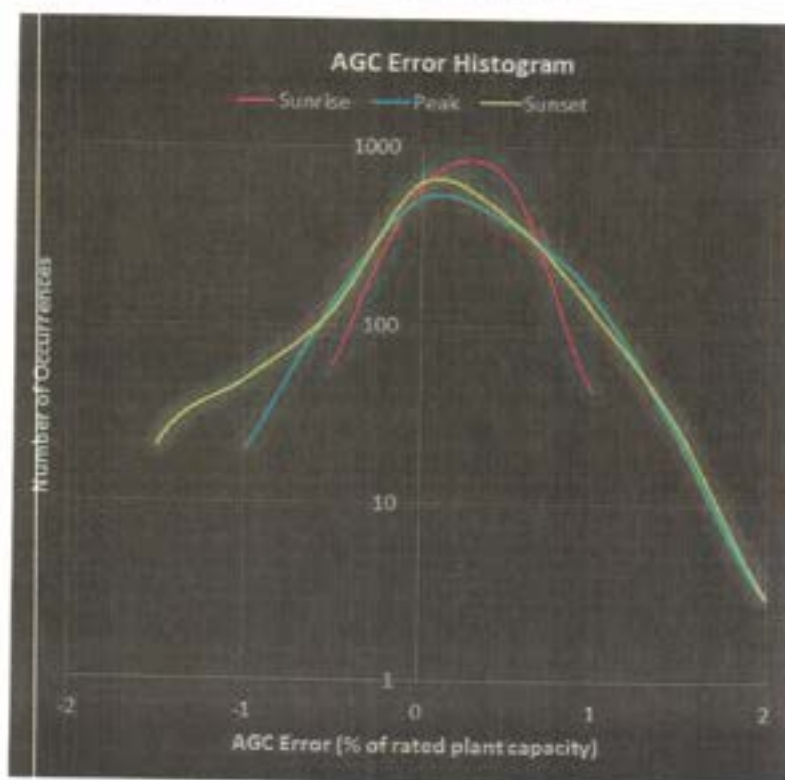

Figure 21. Distribution of AGC control error. *Illustration from NREL*

Normally, CAISO measures the accuracy of a resource's response to energy management system (EMS) signals during 15-minute intervals by calculating the ratio between the sum of the total 4-second set point deviations and the sum of the AGC set points. The future CAISO resource instructed mileage percentage is also being calculated during 15-minute intervals. The plant's monitored delayed response time and the accuracy of the plant's response to the regulation set point changes were used to calculate its regulation accuracy values, which are shown in Table 2 for all three testing periods. Table 3 lists the typical regulation-up accuracies for CAISO's conventional generation for comparison. By comparing the PV plant testing results from Table 2 to the values for individual technologies in Table 3, a conclusion can be made that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The data from these tests will be used by CAISO in the future ancillary service market design to determine the resource-specific expected mileage to award regulation-up and regulation-down capacity.

Table 2. Measured Regulation Accuracy by 300-MW PV Plant

Time Frame	Measured Accuracy of Solar PV Plant
Sunrise	93.7%
Middle of the day	87.1%
Sunset	87.4%

Table 3. Typical Regulation-Up Accuracy of CAISO Conventional Generation

	Combined Cycle	Gas Turbine	Hydro	Limited Energy Battery Resource	Pump Storage Turbine	Steam Turbine
Regulation-Up Accuracy	46.88%	63.08%	46.67%	61.35%	45.31%	40%

4 Frequency Droop Control Tests

4.1 Rationale and Description of Frequency Droop Tests

The ability of a power system to maintain its electrical frequency within a safe range is crucial for stability and reliability. Frequency response is a measure of an interconnection's ability to stabilize the frequency immediately following the sudden loss of generation or load. An interconnected power system must have adequate resources to respond to a variety of contingency events to ensure rapid restoration of the balance between generation and load. On January 16, 2014, FERC approved Reliability Standard BAL-003-1 ("Frequency Response and Frequency Bias Setting"), submitted by NERC. By approving this standard, NERC created a new obligation for balancing authorities, including CAISO, to demonstrate that they have sufficient frequency response to respond to disturbances resulting in the decline of system frequency. The purpose of this initiative is to ensure that CAISO provides sufficient primary frequency response to support system reliability while complying with the new NERC requirement [16]. NERC determines the Western Interconnection's frequency response obligation (IFRO) based on the largest potential generation loss of two Palo Verde generating units (2,626 MW). NERC created this standard to ensure that balancing authorities have sufficient frequency response capability on hand. Like all balancing authorities, CAISO must plan on having an adequate amount of frequency response capability available to respond to actual frequency events. CAISO's estimated frequency response obligation is 258 MW/0.1 Hz. Based on historical events during 2015–2016, CAISO recognized that its median frequency response rate might fall short of its frequency response obligation (FRO) by as much as 100 MW/0.1Hz [16]. From this perspective, the participation of curtailed PV power plants in CAISO's frequency response could help address this potential deficiency. The objective of the frequency response test conducted under this project was to demonstrate that the plant can provide a response in accordance with 5% and 3% droop settings through its governor-like control system.

The definition of implemented droop control for PV is the same as that for conventional generators:

$$\frac{1}{Droop} = \frac{\Delta P/P_{rated}}{\Delta f/60Hz} \tag{5}$$

The plant's rated active power (300 MW) is used in Eq. 5 for the droop setting calculations. For the purposes of the droop test, the plant was set to operate at a curtailed power level that was 10% lower than the available estimated peak power. The PPC was programmed to change the plant's power output in accordance with a symmetric droop characteristic, shown in Figure 22 at both the 5% and 3% droop values. The upper limit of the droop curve was the available plant power, and the lower limit was at a level that was 20% below the then-available peak power. The implemented droop curve also had a ±36-mHz frequency deadband.
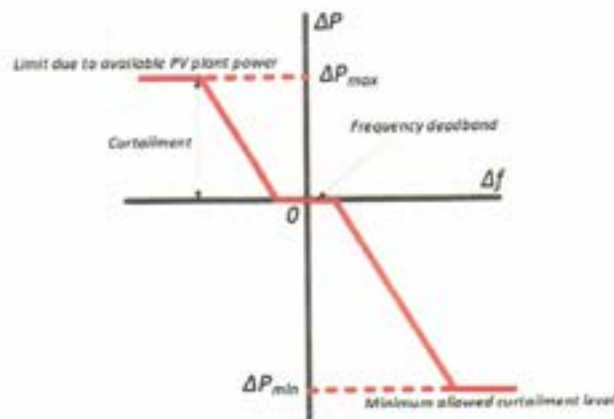
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Figure 22. Frequency droop characteristic. *Illustration from NREL*

The frequency droop capability of the plant was tested using the actual underfrequency and overfrequency events in the Western Interconnection measured by NREL in Colorado (Figure 23 and Figure 24, respectively).
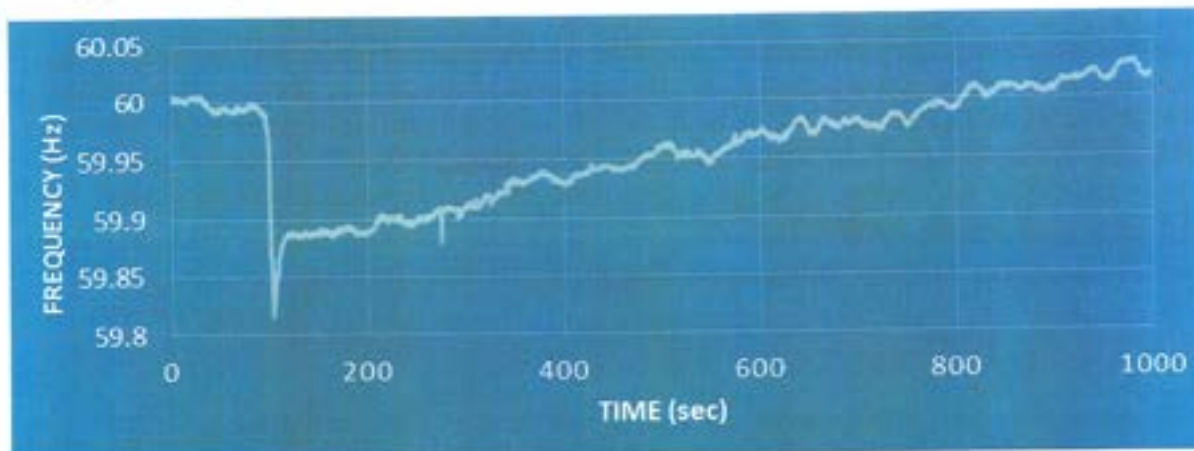

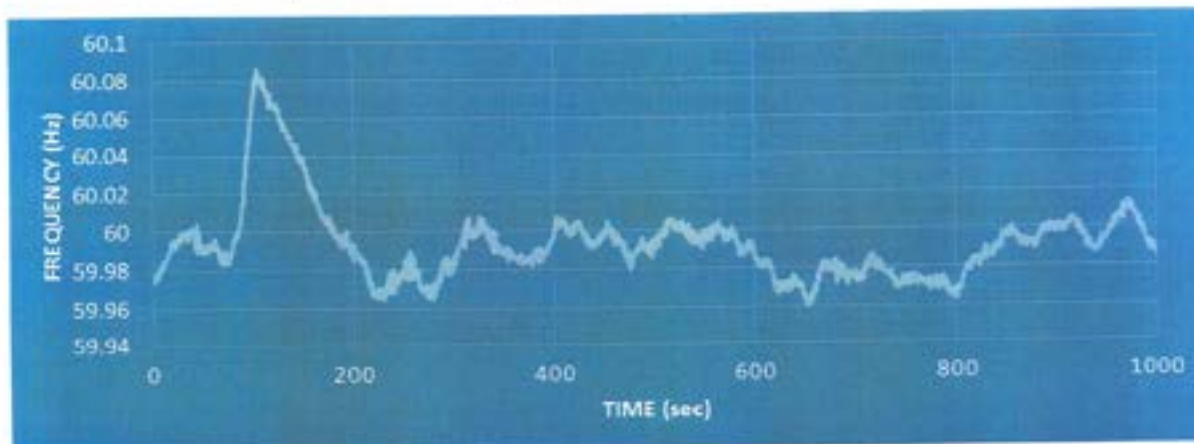**Figure 23. Underfrequency event.** *Illustration from NREL*

Figure 24. Overfrequency event. *Illustration from NREL*

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The frequency event time series shown in Figure 23 and Figure 24 were provided to the PPC, so the plant can demonstrate a frequency response as if it were exposed to a real frequency event measured at the plant's POI. This is the common method for testing the frequency response of inverter-coupled generation because waiting for a real frequency event to occur in the power system may be time consuming because large contingency events do not happen very often (two to three times per month for the Western Interconnection). The active power ramp-rate limit in the PPC was set at 600 MW/min (10 MW/sec) during the droop control tests.

4.2 Droop Test Results

The 5% and 3% frequency droop tests on the 300-MW PV power plant were conducted on August 24, 2016. For this purpose, the First Solar team remotely set the PPC into droop control mode in accordance with the control method shown in Figure 22, with 5% and 3% droop values and 10% power curtailment. The minimum allowed power level for down-regulation was set to 20% below the available peak power for all droop tests (to minimize plant revenue losses).

4.2.1 Droop Tests during Underfrequency Event

The results of one 3% droop test during the morning on August 24, 2016, are shown in Figure 25. The plant's active power response in MW to the underfrequency event was measured by the phasor measurement units at the plant's POI. The calculated active power time series show that the plant increased its power output during the initial grid frequency decline, and then gradually returned to its original pretest level as frequency returned to its normal prefault level. The droop response of the plant can be observed on the X-Y plot shown in Figure 26, wherein a linear dependence between frequency and measured power can be observed once the frequency deviation exceeded the deadband.
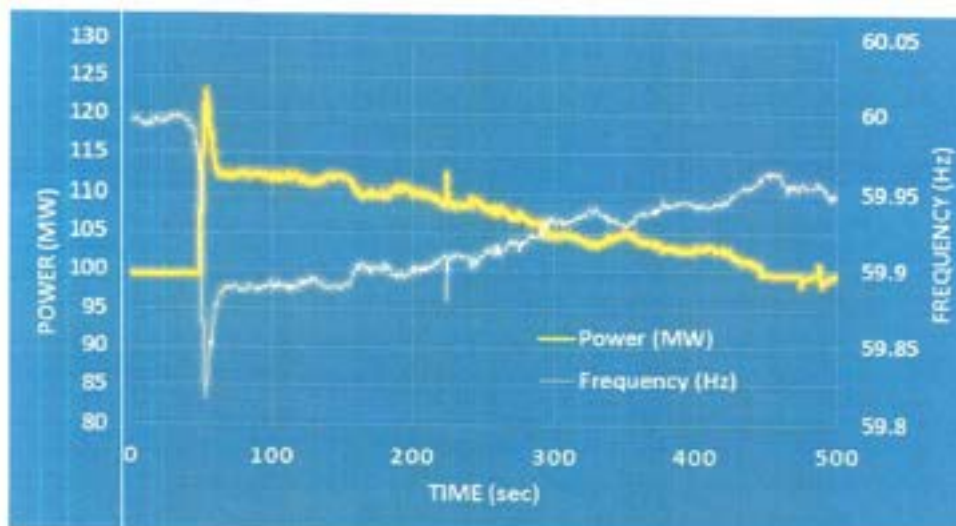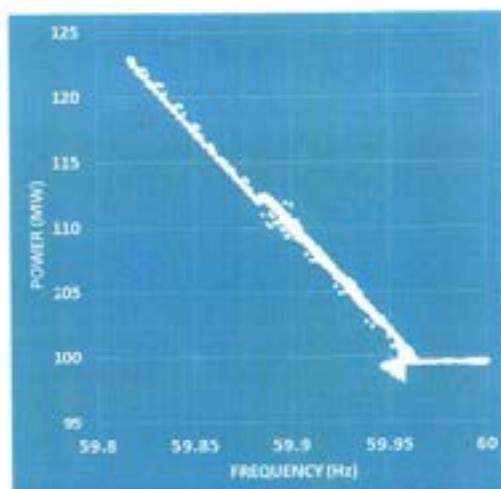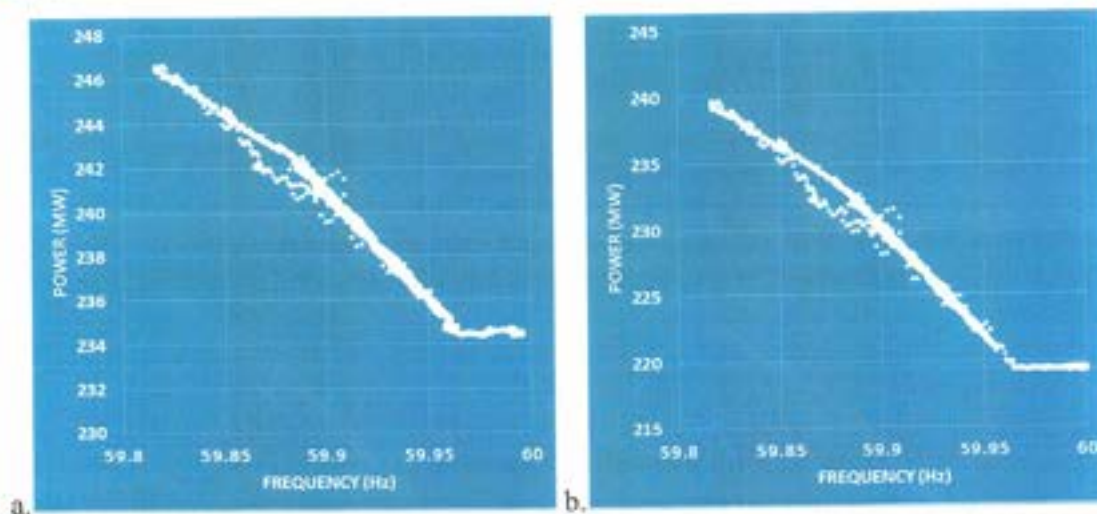

Figure 25. Example of the plant's response to an underfrequency event
(3% droop test during sunrise). *Illustration from NREL*

Figure 26. Measured droop characteristic for an underfrequency event (3% droop test during sunrise)

Similarly, 3% and 5% droop tests were conducted during midday (peak solar production period) and during the afternoon. Example test results for these periods are shown in Figure 27 (a and b) and Figure 28. Some nonlinearity in the plant's response was observed during these tests when the frequency deviation exceeded 120 mHz from its prefault level, causing some mismatch between the expected and actual droop response. Such nonlinearity was not observed during the morning droop tests when the solar resource was increasing steadily during the test under clear-sky conditions. One reason for this mismatch could be the decreasing solar resource and increased resource variability due to cloud conditions during the afternoon. It is expected that further fine-tuning the PPC control parameters can help mitigating such nonlinearity, and the First Solar team will address this issue in the future.

Figure 27. Measured droop characteristics for an underfrequency event: (a) 5% droop test and (b) 3% droop test during midday. *Illustration from NREL*
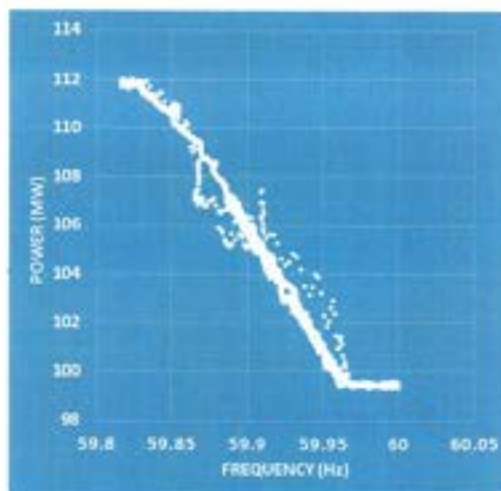
Figure 28. Measured droop characteristics for an underfrequency event (5% droop test during sunset). *Illustration from NREL*

Results of the individual droop tests are shown in greater detail in figures 29–33. The first plot in each figure shows the data points scattered around the calculated target droop characteristic (figures29[a]–33[a]). In these X-Y plots, the X-axis represents the frequency deviation, Δf (or change in frequency), from its prefault value, calculated as:

$$\Delta f = f_{grid} - 60Hz \tag{6}$$

where f_{grid} is the value of grid frequency from the event time series.

The Y-axis represents the plant's active power response, $\Delta P_{measured}$ (or change in the plant's active power output), calculated as:

$$\Delta P_{measured} = P_{actual} - P_{max.estimated} \tag{7}$$

where P_{actual} is the measured plant's active power at the POI, and $P_{max.estimated}$ is the estimated peak power for a given level of solar resource.

The calculated plant response, $\Delta P_{calculated}$ (or target response), for a given droop value can be calculated as (frequency deadband is not included in this equation, but it is added in the control logic):

$$\Delta P_{calculated} = \frac{\Delta f}{60Hz} \cdot \frac{1}{Droop} \cdot P_{nom} \tag{8}$$

where $P_{nom} = 300 \; MW$ is the plant's nameplate capacity.

The droop control error is then calculated as a difference between the calculated target and actual plant response for any given droop setting:

$$Error = \Delta P_{calculated} - \Delta P_{measured} \tag{9}$$

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The frequency distribution of the control error data for each droop test along with the error statistics data are shown in figures29(b)–33(b). The detailed comparison of these test results concluded that the PV plant demonstrated a satisfactory droop performance during the underfrequency events for the morning, midday, and afternoon time frames. Some nonlinearities in the response can be further improved by fine-tuning the controller parameters. The observed scatter around the target response is due to the short-term solar resource variability, and it can be mitigated if such a response is generated by a number of PV plants within a larger geographical footprint.
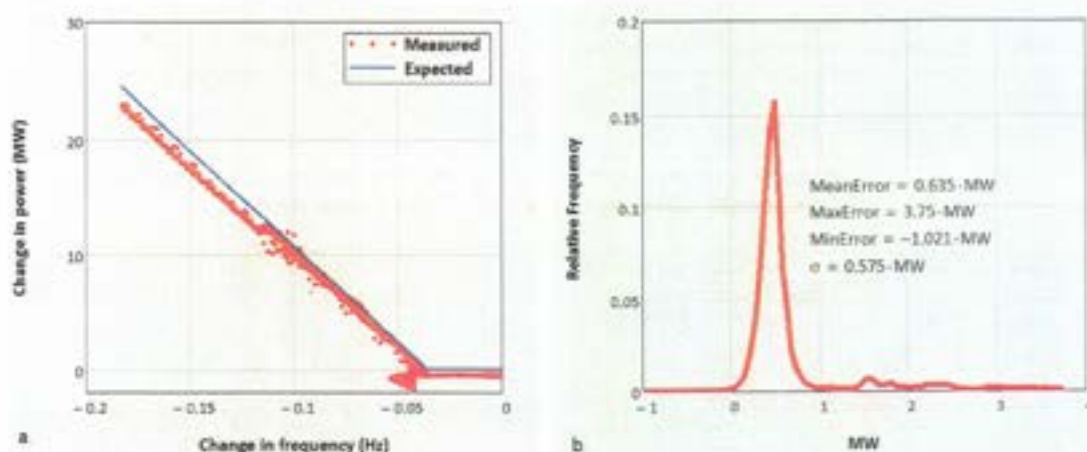

Figure 29. (a) Results and (b) control error during the sunrise 3% droop test for an underfrequency event. *Illustration from NREL*
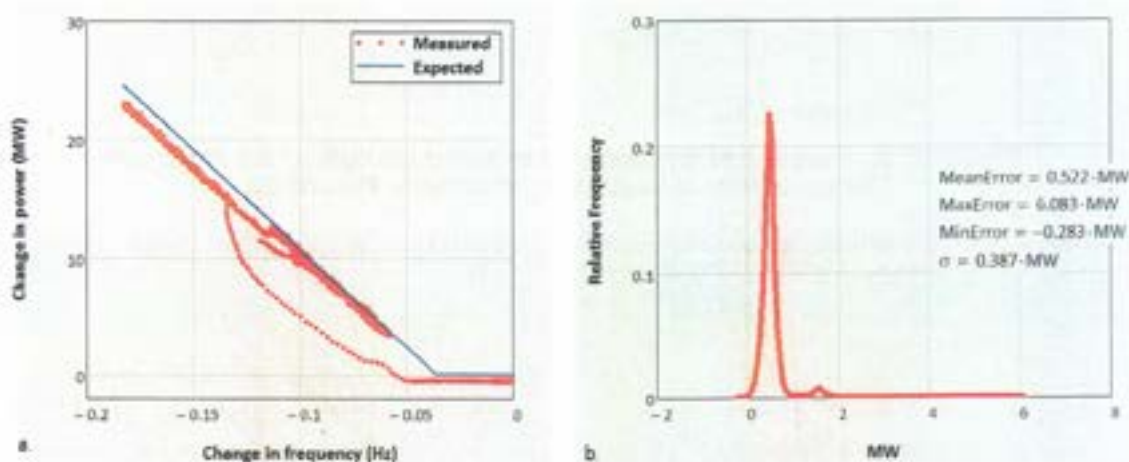

Figure 30. (a) Results and (b) control error during a second sunrise 3% droop test for an underfrequency event. *Illustration from NREL*
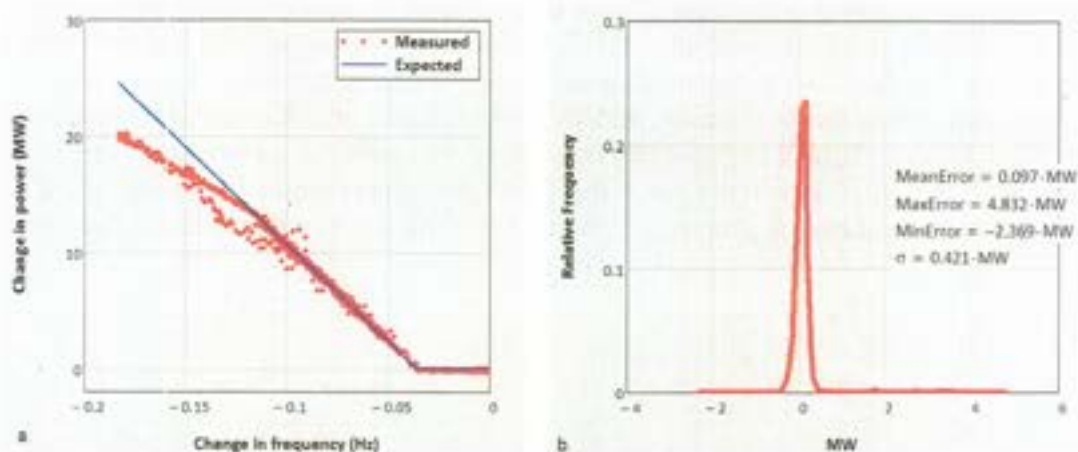
28

Figure 31. (a) Results and (b) control error during the midday 3% droop test for an underfrequency event. *Illustration from NREL*
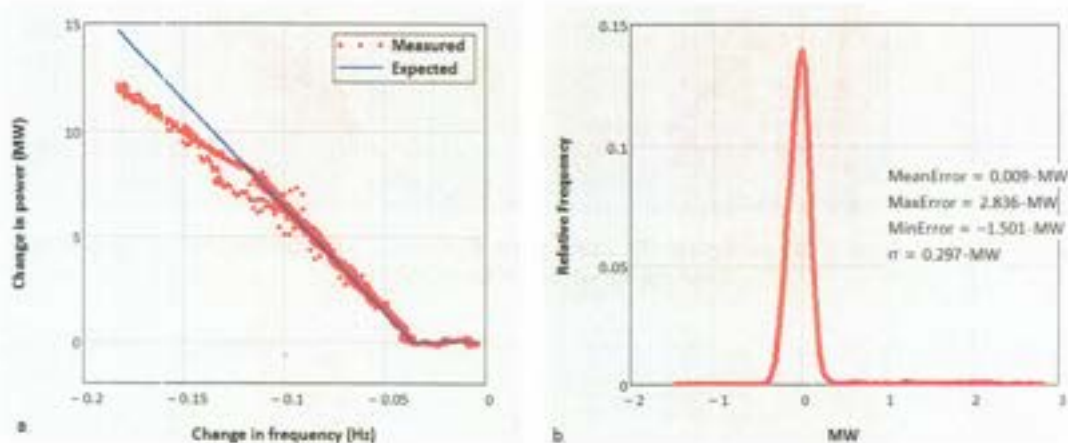

Figure 32. (a) Results and (b) control error during the midday 5% droop test for an underfrequency event. *Illustration from NREL*
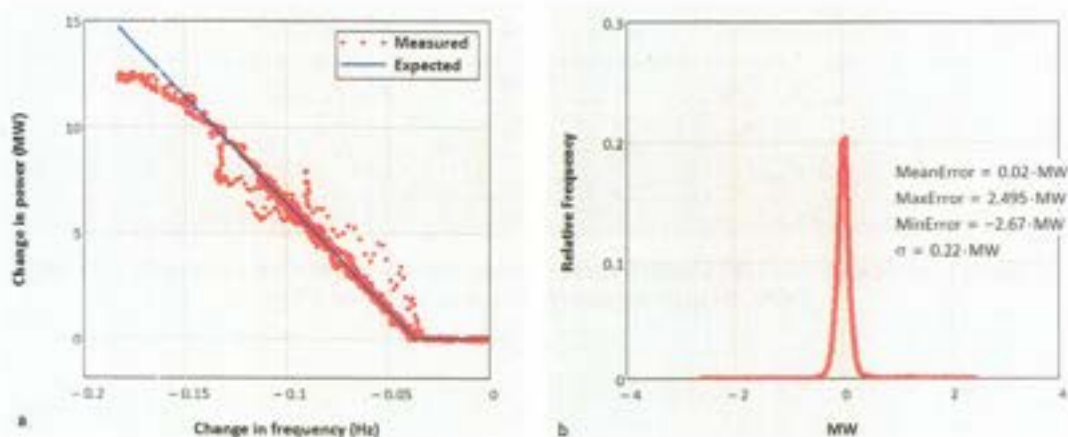

Figure 33. (a) Results and (b) control error during the sunset 5% droop test for an underfrequency event. *Illustration from NREL*

Table 4 and Table 5 show the control error statistics for the underfrequency droop tests in absolute MW units and percentage of plant capacity, respectively. Despite observed nonlinearities and scatter, the mean control error is very small, ranging from 0%–0.21% of the plant's rated capacity. The standard deviation control error is also small (0.07%–0.19% of rated capacity). The largest measured positive and negative error values are 2.03% and -0.89% of the plant's rated capacity. Figure 34 shows the consolidated data for many up-regulation tests for comparison.

Table 4. Droop Control Error Statistics (Absolute Values in MW)

Test Type	Mean Error (MW)	Max + Error (MW)	Max – Error (MW)	Standard Deviation (MW)
3% droop, sunrise	0.63	3.75	-1.02	0.57
3% droop, sunrise	0.52	6.08	-0.28	0.39
3% droop, midday	0.1	4.83	-2.37	0.42
5% droop, midday	0.0	2.84	-1.5	0.3
5% droop, sunset	0.02	2.5	-2.67	0.22

Table 5. Droop Control Error Statistics (Percentage of Plant Rated Capacity)

Test Type	Mean Error (%)	Max + Error (%)	Max – Error (%)	Standard Deviation (%)
3% droop, sunrise	0.21	1.25	-0.34	0.19
3% droop, sunrise	0.17	2.03	-0.09	0.13
3% droop, midday	0.03	1.61	-0.79	0.14
5% droop, midday	0.00	0.95	-0.5	0.1
5% droop, sunset	0.01	0.83	-0.89	0.07